Commonwealth of Kentucky
Division for Air Quality

PERMIT STATEMENT OF BASIS

TITLE V PERMIT NO: V-02-043 REVISION 2
Louisville Gas and Electric Company
P.O. Box 32010, Louisville, Kentucky, 40232

BEN MARKIN, REVIEWER
SOURCE I.D. #: 021-223-00002
SOURCE A.I. #: 4054
ACTIVITY #: APE 20040003

1. EXECUTIVE SUMMARY

Louisville Gas and Electric Company (LG&E), as operator, submitted an air permit application dated December 01, 2004, to construct a new 750 megawatt (MW) net nominal generating unit that will utilize supercritical pulverized coal (SPC) technology at its existing Trimble County Generating Station located west of Bedford in Trimble County, Kentucky. The new SPC boiler will be equipped with Selective Catalytic Reduction (SCR), Pulse Jet Fabric Filters (PJFF), a Wet Flue Gas Desulfurization (WFGD) System, and a Wet Electrostatic Precipitator (WESP). It will exhaust through two exhaust flues located within an existing common chimney and will be equipped for ASTM Grade No. 2-D S15 that can not exceed a sulfur content greater than 15 ppm fuel oil for start-up and stabilization. Existing equipment at the Trimble County Generating Station includes the following: a 500 MW (nominal rated capacity) pulverized coal generating unit (Emissions Unit 1), six 160 MW (nominal rated capacity) simple cycle natural gas combustion turbines (Emissions Units 25-30), a natural draft cooling tower, coal/limestone/ash/gypsum material handling equipment, three auxiliary boilers, an emergency diesel generator, and fuel oil storage tanks. The existing natural draft cooling tower, coal/limestone/ash/gypsum material handling equipment, and fuel oil storage tanks will have increased utilization when the new SPC boiler becomes operational. The new facilities that will be constructed as part of this proposed project will include the SPC boiler (Emissions Unit 31), a linear mechanical draft cooling tower (LMDCT) for Emissions Unit 1, a coal blending facility, dust collectors and dust suppression equipment on material handling operations, an ash barge loading system/fly ash silos, an auxiliary steam boiler, a backup diesel generator, and an emergency diesel fire water pump engine. The seven existing combustion units (Emissions Unit 1 and Emissions Units 25 -30) are not part of the proposed major modification, and have previously gone through Prevention of Significant Deterioration (PSD) review. The proposed project constitutes a major modification of a major stationary source as defined in 401 KAR 51:017, Prevention of Significant Deterioration of Air Quality. The proposed project will result in a significant net emissions increase, as defined in 401 KAR 51:001 Section 1(146), of the following regulated air pollutants: particulate matter (PM & PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), fluorides, and sulfuric acid (H_2SO_4) mist. The proposed project is not subject to PSD review for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) based on contemporaneous and creditable emission reductions of NO_x and SO_2 from the existing PC boiler (Emissions Unit 1). The source has chosen a twenty four (24) month baseline of actual SO_2 emission for Unit 1 for the period of January 1, 2001 to December 31, 2002. For NOx, the baseline was January 1, 2000 to December 31, 2001. The emissions reductions from Emissions Unit 1 will be such that there will be no significant net emissions increase of NO_x and SO_2 thus removing these two pollutants from this PSD review. In addition, the project will not emit lead above the significant emission rate for lead of 0.6 tons per year (tpy), set forth in 401 KAR 51:001 Section 1(221) and 40 CFR 51. Emissions from the project of hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds will also be below significant emission levels and are therefore not subject to PSD review.

The Trimble County Generating Station is located in a county classified as “attainment” or “unclassified” for each of the PSD applicable pollutants pursuant to 401 KAR 51:010, Attainment Status Designations. The Trimble County Generating Station is an existing major stationary source under the PSD regulations as defined in 401 KAR 51:001, Section 1(120). The proposed project meets the definition of a major modification and is subject to evaluation and review under the provisions of the PSD regulation for PM & PM_{10}, CO, VOC, fluorides, and H_2SO_4 mist. A PSD review involves the following six requirements:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40 CFR Parts 60, 61, and 63.
3. Air quality impact analysis.
4. Class I area impact analysis.
5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

Furthermore, the source will also be subject to Title V, Title IV Phase II Acid Rain and NO_x SIP Call permitting. The Title V permitting procedures are contained in 401 KAR 52:020. The Title IV permitting procedures are within 401 KAR 52:020, Permits, 401 KAR 52:060, Acid Rain Permit, 40 CFR Part 72, 40 CFR Part 76 and 40 CFR 97. NO_x SIP Call permitting procedures are within 401 KAR 51:160 and 40 CFR 96. This Statement of Basis addresses the proposed conditions of the PSD/Title V permit and the Title IV Phase II Acid Rain permit. The preliminary PSD determination is also provided within this Statement of Basis for the Title V permit. This review demonstrates that all regulatory requirements will be met and includes a draft permit that would establish the enforceability of all applicable requirements. This review is to ensure that the source shall be considered in compliance with all applicable requirements, as of the date of permit issuance for the applicable requirements that are specifically identified in the permit, and specifically identified requirements that have been determined to not be applicable to the source

Louisville Gas & Electric Company submitted a minor revision application to the Division on April 29, 2005 for a voluntary creditable decrease in emissions for the permitted Unit 1, a 5,333 mmBtu/hr, pulverized coal-fired boiler installed in 1990. The creditable decrease in emissions will be 3,225 tons per year of sulfur dioxide. This permit will limit the twelve (12) month rolling total on the unit sulfur dioxide (SO_2) on the unit to 4,822 tons per year. The credible reduction is requested by the facility to net against future potential increase from the construction of the additional utility boiler (TC2). The practically enforceable creditable reduction is being done in accordance with new source review (NSR) rules. [401 KAR 51:001 and 401 KAR 51:017] Compliance with the emissions limit shall be demonstrated using continuous emission monitoring equipment which measures the emissions hourly and procedures required by 401 KAR 52:060 (acid rain program). The sulfur dioxide limit shall become effective January 1, 2006. A previous minor permit revision limited nitrogen oxide emissions from Unit 1 to 5,556 tons per year, a credible decrease of 1,485 tons per year. That limit was effective January 1, 2005.

2. BACKGROUND

On December 01, 2004, the Division received a permit application to construct and operate a SPC boiler, and associated support equipment, for electricity generation from LG&E. The application was logged administratively complete on January 29, 2005.

3. EMISSIONS ANALYSIS

The new SPC boiler (Emissions Unit 31) is equipped with Selective Catalytic Reduction (SCR), Pulse Jet Fabric Filters (PJFF), a Wet Flue Gas Desulfurization (WFGD) System, and a Wet Electrostatic Precipitator (WESP). Additional processes at the facility will include a ASTM Grade No. 2-D S15 or equivalent fuel oil-fired auxiliary steam boiler (to operate 1,000 hours or less per year); a diesel emergency fire water pump engine (to operate 52 hours or less per year); a backup diesel generator (to operate 1,000 hours or less per year); new coal blending system and associated material handling equipment; increased utilization of existing material handling equipment; increased utilization of the existing natural draft cooling tower; a linear mechanical draft cooling tower (LMDCT) for Unit 1; increased utilization of the existing fuel oil storage tanks; and an ash barge loading system/fly ash silos. Detailed descriptions of the plant processes and expected emissions at each emissions point and emissions unit are contained in the air permit application document (refer to Section 2.3 of the air permit application). In addition, hourly and annual emission rates and pollutant identification for each respective emission unit can be referenced from the application. Emissions were based on the maximum rated capacity of the proposed project, anticipated operating conditions, and 8,760 hours per year after control technologies were applied. The project's annual net emissions increases for PSD-regulated pollutants and mercury, as shown below in Table 3-1 and in Table 2-2 of the application, are calculated for anticipated conditions while operating at 100% load. Evaluations at 50% and 75% load were also performed as well as for three potential coal fuels.

TABLE 3.1 – Net Emissions Increase for PSD-Regulated Pollutants

Pollutants	Net Emissions Increase (tpy)
Carbon Monoxide (CO)	3,040.8
Nitrogen Oxides (NO_x)	38*
Particulate Matter (PM/PM_{10})	567.4
Sulfur Dioxide (SO_2)	39**
Volatile Organic Compounds (VOC)	97.8
Sulfuric Acid (H_2SO_4) Mist	116.6
Fluorides	6.8
Lead (Pb)	0.55
Total Reduced Sulfur	Negligible
Reduced Sulfur Compounds	Negligible
Hydrogen Sulfide	Negligible
Mercury (Hg) (non PSD pollutant)	0.043

* On January 4, 2005, the Division for Air Quality (Division) approved LG&E's minor permit revision that contained an enforceable emissions limit such that the consecutive twelve-month rolling total of NO_X emissions from Emissions Unit 1 shall not exceed 5,556 tpy. The emissions decrease for Emissions Unit 1 of 1,485 tpy of NO_X is realized as both contemporaneous and creditable. The proposed project is not subject to PSD review for NO_X.

** On May 2, 2005, the Division received LG&E's minor permit revision that contained an enforceable emissions limit such that the consecutive twelve month rolling total of SO_2 emissions from existing Emissions Unit 1 shall not exceed 4,822 tpy. The emissions decrease for Emissions Unit 1 of 3,225 tpy of SO_2 is realized as both contemporaneous and creditable. The proposed project is not subject to PSD review for SO_2.

As the notes to Table 3.1 indicate, LG&E has accepted a new lower limit on its allowable emissions of NO_x and SO_2 from the existing PC boiler (Emissions Unit 1). These lowered limits are less than Trimble's historical emissions and represent real reductions. These emissions reductions will offset nearly all of the NO_x and SO_2 emissions increases due to the proposed Project. Taken together, the emissions decreases at Emissions Unit 1 and the emissions increases due to the Project will result in a net emissions increase in NO_x of 38 tpy and in SO_2 of 39 tpy. This netting analysis is based on the operation of 8760 hours/year at the rated capacity. Actual emissions are expected to be much less. These net emissions increases are not considered significant under 401 KAR 51:001 Section 1(221). Therefore, the Project is not subject to PSD BACT review for NO_x and $SO_{2.}$

Pursuant to 401 KAR 51:017, the creditable emissions reductions from Emissions Unit 1 were determined by the difference between Emissions Unit 1's post-change enforceable emissions limits and the pre-change baseline actual emissions (BAE). For an Electric Utility Steam Generating Unit (EUSGU), the BAE is calculated as the emission rate, in tons per year, based on the actual emissions determined over a consecutive 24-month period during the 60-month period preceding the contemporaneous emissions change. Specifically, the baseline look back period for Emissions Unit 1 is the 60-month period preceding the date on which an enforceable permit limit for SO_2 and NO_x is taken, respectively. The source has chosen a twenty four (24) month baseline of actual SO_2 emission for Unit 1 for the period of January 1, 2001 to December 31, 2002. For NOx, the baseline was January 1, 2000 to December 31, 2001.

Capital investment and increased operating and maintenance (O&M) costs are required to implement the reductions at Emissions Unit 1. For NO_x, LG&E will reduce NO_x emissions through a combination of increased removal efficiency and increased SCR operating time. For SO_2, LG&E will decrease SO_2 emissions through capital investments to increase overall WFGD removal efficiency. Additionally, for these reductions to be considered contemporaneous and therefore eligible for consideration in the netting analysis, they must occur within the period beginning 60-months before initiation of construction of the Project (construction of TC2 and associated equipment) and before the initial operation of the Project.

The Division has established that the change in method of operations for the existing Trimble County Generation Station is marked by the initiation of the change to Emissions Unit 1's NO_x and SO_2 emission limits by an enforceable permit action. Thus, the BAE for Emissions Unit 1 for netting purposes, on a pollutant-by-pollutant basis, begins 60-month period prior to, and ends on, the date of the enforceable permit action for NO_x and SO_2, respectively. Table 3.2 identifies the creditable decreases at Emissions Unit 1.

TABLE 3.2 – Creditable Emissions Decreases at Emissions Unit 1 (TPY)

	Baseline Actual Emissions	New Limits	Creditable Decreases
NO_x	7,041	5,556	1,485
SO_2	8,047	4,822	3,225

LG&E submitted to the Division two minor revision applications on November 29, 2004 and**,** April 29, 2005, to establish the new limits reflected in Table 3.2. Compliance with the new limits shall be demonstrated using continuous emission monitoring equipment and procedures required by 401 KAR 52:060 (acid rain program). The enforceable annual tonnage limit for NO_x will be achieved using the installed selective catalytic reduction (SCR). The enforceable annual tonnage limit for SO_2 will be achieved using the upgraded wet limestone flue gas desulfurization (WFGD) system.

In order to determine the net emissions increases for the proposed Project for NO_x and SO_2, the Division determined the contemporaneous period for the Project and identified all emissions increases and decreases that are contemporaneous and creditable pursuant to 401 KAR 51:001 Section (1)(146). The contemporaneous period for the proposed Project is the period 60-months prior to the start of construction through the period in which the Project starts operation. For this Project, the construction period is projected at 5-years, resulting in a 10-year period. The Division has concluded that no other creditable emission increases or decreases have occurred within the contemporaneous period for the Project. The Trimble County Generating System was most recently subject to PSD review in January 2001 for the construction of six simple cycle natural gas combustion turbine peaking units. Table 3.3 summarizes the PSD netting for NO_x and SO_2.

TABLE 3.3 – PSD Netting Summary (TPY)

	Emissions Unit 1 Creditable Decreases	Project Emissions Increases	Net Emissions Increase	Significant Emissions Rate*
NO_x	1,485	1,523	38	40
SO_2	3,225	3,264	39	40

* Significant emission rate as given in 401 KAR 51:001 Section 1(221)

4. REGULATORY REVIEW

This section presents a discussion of the air quality regulations applicable to this project in addition to the PSD requirements. In some cases the emission limit or technology standard based on these regulations may be superseded by the BACT requirements which are more stringent under PSD (see Section 5, Best Available Control Technology Review).

The following regulations apply to the proposed project

New Source Performance Standards (NSPS)

The Federal Clean Air Act (FCAA) directed U.S. EPA to establish New Source Performance Standards, or NSPS, for specific industrial categories. There are five NSPS applicable requirements to the proposed project.

New Source Performance Standards for Steam Electric Generating Units

40 CFR Part 60, Subpart Da requires all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 250 mmBtu/hour for which construction is commenced after September 18, 1978 (44 FR 33613, June 11, 1979) to meet limitations on emissions of PM, SO_2, and NO_x. In 1998, U.S. EPA revised Subpart Da for new electric utility steam generating units (63 FR 49442, September 16, 1998). The revisions reduced the numerical NO_x emission limits for utility steam generating units for which construction commenced after July 9, 1997. The revisions established a NO_x emission limit of 1.0 lb/megawatt-hour gross energy output (lb/MWh), based on a 30-day rolling average. The new SPC boiler will be subject to Subpart Da. Subpart Da is incorporated by reference in 401 KAR 60:005 Section 3(1)(c).

On February 28, 2005, U.S. EPA proposed in the Federal Register revised NO_x, SO_2 and PM emission limits under 40 CFR Part 60, Subpart Da, for all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 250 mmBtu/hour for which construction is commenced after February 28, 2005. (70 FR 9706, February 28, 2005). The emission limits proposed by LG&E for Emissions Unit 31 are lower than the revised emission limits proposed by U.S. EPA for NO_x and SO_2 emissions. LG&E has proposed a PM emission limit of 0.018 lb/mmBtu (filterable and condensable), which is different than the revised PM limit proposed by U.S. EPA of 0.015 lb/mmBtu for PM (filterable). In order to meet the revised PM limit proposed by U.S. EPA under the NSPS, LG&E has also proposed an emission limit of a 0.015 lb/mmBtu (filterable) for Emissions Unit 31, in addition to the 0.018 lb/mmBtu PM limit for filterable and condensable PM. Periods of startup were not included in this proposed regulation. The proposed NSPS limits are included in this permit and will be met by this project. In the event that the final NSPS is changed, then this permit will be reopened pursuant to the requirement of 401 KAR 52:020 and appropriate changes made.

On May 18, 2005, U.S. EPA published in the Federal Register the Clean Air Mercury Rule (CAMR) establishing new mercury emission limits under 40 CFR Part 60, Subpart Da for all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 250 mmBtu/hour for which construction is commenced after January 30, 2004 (70 FR 28606). The emission limit proposed by LG&E for Emissions Unit 31 is lower than the new emission limit adopted by U.S. EPA for mercury in Subpart Da. The CAMR also adds new 40 CFR Part 60, Subpart HHHH, which establishes a nation-wide cap on mercury emissions from utility units. Emissions Units 31 will also be subject to Subpart HHHH, at the time the state adopts this rule into its State Implementation Plan.

New Source Performance Standards for Coal Preparation Plants

40 CFR Part 60, Subpart Y, Standards of Performance for Coal Preparation Plants, incorporated by reference in 401 KAR 60:005 Section 3(1)(ff), requires certain coal processing facilities to comply with certain particulate standards. Activities regulated by this NSPS include crushing, screening, conveying and transferring of coal. Emission points are subject to an opacity limitation of 20 percent (%). The proposed BACT emission limits for coal processing activities subject to Subpart Y will meet all NSPS requirements.

New Source Performance Standards for Non-Metallic Mineral Processing Plants

40 CFR Part 60, Subpart OOO, Standards of Performance for Non-Metallic Processing Plants, incorporated by reference in 401 KAR 60:670, regulates particulate emissions from crushing, screening, milling, transferring and truck unloading of non-metallic minerals. Operations enclosed in buildings are allowed zero fugitive emissions. Emissions vented through a stack are limited to 7% opacity and 0.05 grains per dry cubic meter (gr/dcm). Conveyors and transfer points are allowed 10% fugitive visible emissions, while crushing operations are allowed 15% opacity if a capture system is not used. Trucks unloading into screening operations, hoppers or crushers are exempt from the NSPS Subpart OOO standard, but are subject to the requirements of 401 KAR 63:010 (discussed below). The proposed BACT emission limits for non-metallic mineral processing activities subject to Subpart OOO will meet these NSPS requirements.

New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Dc, incorporated by reference in 401 KAR 60:005 Section 3(1)(e), regulates all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 10 mmBtu/hour and no more than 100 mmBtu/hour for which construction is commenced after June 9, 1989 (55 FR 37683, September 12, 1990). Under Subpart Dc,

opacity is limited to 20% (6 minute average), except for one 6-minute period per hour of not more than 27% opacity. Subpart Dc limits SO_2 emissions to less than 0.5 lb/mmBtu or firing oil with less than 0.5% sulfur by weight. The proposed auxiliary steam boiler will be subject to Subpart Dc, since it will be constructed after June 9, 1989. The proposed BACT emission limits for the auxiliary steam boiler will ensure these NSPS requirements are met.

On February 28, 2005, U.S. EPA proposed in the Federal Register a new PM emission limit of 0.03 lb/mmBtu for oil fired units regulated under 40 CFR Part 60, Subpart Dc (70 FR 9706, February 28, 2005). LG&E proposed a PM emission limit of 0.05 lb/mmBtu (refer to air permit application document, Appendix E, Auxiliary Boiler Data), which was greater than the new limit proposed by U.S. EPA of 0.03 lb/mmBtu for PM (filterable). The applicant has therefore revised the PM emission limit from the originally proposed level of 0.05 lb/mmBtu to 0.03 lb/mmBtu to comply with the proposed NSPS PM limit of 0.03 lb/mmBtu for PM (filterable). Therefore, both the existing and proposed NSPS requirements will be met for the auxiliary steam boiler.

A. State Requirements

The Commonwealth of Kentucky has developed specific new source standards in 401 KAR 59:016 for new electric utility steam generating units. 401 KAR 59:016 standards apply to each electric utility steam-generating unit built after September 19, 1978, that is capable of combusting more than 250 mmBtu/hr heat input of fossil fuel. Additionally, Kentucky has developed new source standards in 401 KAR 59:015 which apply to indirect heat exchangers built after the classification dates and that are capable of a heat input capacity greater than 1 mmBtu/hr. 401 KAR 59:015 does not apply to units that are subject to the requirements of 401 KAR 59:016. Kentucky's emission standards parallel the Federal NSPS standards; therefore, the proposed facility will also be in compliance with Kentucky's emission standards if it is in compliance with NSPS standards.

401 KAR 63:010 applies to fugitive dust emissions from roads and material handling operations. The regulation requires the owner or operator to utilize reasonable precautions to prevent particulate matter from becoming airborne and prohibits visible fugitive dust at the property line. LG&E has proposed controls on such operations, such as watering, paving roads, and covering or enclosing operations, to ensure compliance with this regulation.

401 KAR 63:020 applies to certain facilities that emit potentially hazardous matter or toxic substances that are not elsewhere subject to regulation. The same control technologies and emissions limitations that are applied for PM, SO_2, CO, VOC and fluorides ensure that the proposed facilities will not emit potentially hazardous matter or toxic substances, including products of coal combustion such as non-mercury metallic substances, acid gases, and

hazardous organic substances, in violation of 401 KAR 63:020, and that such matter and substances will be controlled to levels that are not deemed to threaten health or welfare. These controls ensure that the facilities are operated using the utmost care and consideration, as demonstrated by acceptance of PM and mercury emissions limits that meet or exceed the newly promulgated and proposed U.S. EPA performance standards.

NO_x SIP Call

40 CFR Part 96 requires Electric Generating Units (EGUs) to comply with NO_x emissions limitations during the ozone season (May through September). The Emissions Unit 31 at the Trimble County Generating Station will be an EGU and will meet all applicable emission limitations as specified in the NO_x SIP Call regulations (401 KAR 51:160 and 401 KAR 51:190) that have incorporated by reference the requirements of 40 CFR Part 96.

B. Maximum Achievable Control Technology Standards (MACT)

40 CFR 63, Subpart B, Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections, Sections 112(g) and 112(j) ("Case by Case MACT")

Section 112(n)(1)(A) of the FCAA required U.S. EPA to conduct a study to examine the hazards to public health that are reasonably anticipated to occur as a result of hazardous air pollutant (HAP) emissions from electric utility steam generating units after imposition of the requirements of the FCAA. That section also provides that U.S. EPA shall regulate utility units under Section 112 if U.S. EPA determines that such regulation is "appropriate and necessary." In December 2000, U.S. EPA determined that it was "appropriate and necessary" to regulate coal-fired utility units under Section 112 based primarily on emissions of mercury from such units and added such units to the Section 112(c) list of regulated source categories (65 FR 79825, December 20, 2000).

Following U.S. EPA's December 2000 regulatory finding, Section 112(g) of the FCAA required new coal-fired utility units to implement a Maximum Achievable Control Technology (MACT) emission limitation for new sources. This MACT standard is determined on a case-by-case basis pending promulgation of a MACT emission standard and may not be less stringent than the emission control achieved in practice by the best-controlled similar source. In January 2004, U.S. EPA proposed a number of approaches for reducing mercury emissions from coal-fired utility units and requested comments. The proposed approaches included a mercury MACT emission standard under Section 112(d) of the FCAA, specific standards of performance for mercury under Section 111 of the FCAA, or regulation of mercury emissions from utility units under Section 112(n)(1)(A) of the FCAA. (69 FR 4652, January 30, 2004).

On March 29, 2005, U.S. EPA published in the Federal Register a final decision revising and reversing its December 2000 regulatory finding that it was "appropriate and necessary" to regulate coal-fired utility units under Section 112 of the FCAA and removing such units from the list of regulated source categories (70 FR 15994, March 29, 2005).

In its permit application, LG&E submitted to the Division a case-by-case MACT determination in accordance with the then-applicable requirements of 401 KAR 63:002 Section 3(1)(b) and 40 CFR Part 60, Subpart B. Information provided in the permit application and in recent U.S. EPA rulemakings indicates that the emission limitation being proposed for Emissions Unit 31 is not less stringent than the emission limitation achieved in practice by the best controlled similar source and reflects the maximum degree of reduction of emissions of HAPs that the Division determines is achievable, taking into account applicable regulatory considerations. U.S. EPA's proposed approaches for reducing mercury emissions include maximum control of mercury from coal-fired utility units based on utilization of control technologies applicable to that category of sources, specifically SCR, PJFF, and WFGD. These are the control technologies proposed for the new SPC boiler (Emissions Unit 31) in addition to a WESP, which should also aid in the removal of mercury. LG&E has proposed an emission limitation for mercury of 13×10^{-6} pounds per MW hour (lbs/MWh) (12-month rolling average, gross output), which is based on the more stringent mercury emission limitations proposed by U.S. EPA in January 2004 and which is below the newly-promulgated mercury limits applicable to this unit under Subpart Da. The proposed emission rate is based on a blend of eastern bituminous and western sub-bituminous coals being fired in the new SPC boiler.

All relevant requirements for HAPs pursuant to a case-by-case MACT were included in the application. Subsequent rule making by U.S.EPA has rendered this portion of the application unnecessary. As U.S. EPA rulemaking is undergoing legal challenges, the Division has retained the MACT analysis in the permit discussion. The mercury limit contained in this permit is significantly lower than that required by the NSPS.

40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

The auxiliary steam boiler is an affected source under the Industrial Boiler MACT, 40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. The Industrial Boiler MACT was published on September 13, 2004 (69 FR 55218, September 13, 2004). The auxiliary steam boiler, based on its heat input rating and capacity factor, will be considered as a new large liquid fuel boiler under the MACT. 40 CFR Part 63, Subpart DDDDD, places restrictions on PM, HCl, and CO emissions from new large liquid fuel fired boilers. PM is restricted to 0.03 lb/mmBtu, HCl is restricted to 0.0005 lb/mmBtu, and CO is restricted to 400 ppmvd (3-run average). The CO limit is a work practice standard. Being an affected new source, the auxiliary steam boiler has to demonstrate compliance with the MACT requirements upon startup. LG&E will demonstrate initial compliance by including a signed statement in the Notification of Compliance Status that indicates that the auxiliary steam boiler will burn only liquid fossil fuels other than residual oils, either alone or in combination with other gaseous fuels.

40 CFR Part 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The backup diesel generator is a compression ignition engine that falls under 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, promulgated June 15, 2004 (69 FR 33474, June 15, 2004). This generator is required to meet the MACT standard of this subpart, since it will be located at a site where the potential exists to emit HAP levels greater than the threshold limitations. To comply with this standard, the applicant proposes to limit the formaldehyde emissions of the engine to 580 ppbvd or less at 15% oxygen. Demonstration of this limit shall be shown by completion of a performance test in accordance with the test procedures provided in Subpart ZZZZ. Operating parameters recommended by the engine supplier, such as exhaust temperature and fuel-to-air mixture, shall be monitored on a continuous basis to demonstrate ongoing compliance. The final determination of the parameters to monitor shall be established upon the final engine selection.

C. Phase II Acid Rain Permits

Title IV of the FCAA requires reductions in emissions of SO_2 and NO_x in an effort to reduce formation of acid rain. U.S. EPA, in promulgating regulations in 40 CFR Part 72, incorporated by reference in 401 KAR 52:060, requires the submittal of application forms no later than two years prior to commencing operations of a regulated unit. LG&E is required to apply for a Phase II Acid Rain permit for Emissions Unit 31. Under Phase II Acid Rain requirements, filing of a Title V application for a new source subject to the Acid Rain requirements requires the source to file the Phase II application at the same time. Additionally, Part 75 requires continuous emission monitoring for NO_x and SO_2. Proposed emission limits for NO_x and SO_2 are lower than Title IV Acid Rain requirements. Therefore, Title IV requirements will be met.

D. Compliance Assurance Monitoring

Emissions of H_2SO_4 mist and fluorides from Emissions Unit 31 are subject to the compliance assurance monitoring (CAM) requirements of 40 CFR Part 64. Pursuant to 40 CFR 64.2, CAM applies on a pollutant-by pollutant basis at emission units at Title V major sources provided the unit is subject to an emission limitation or standard in an applicable requirement, the unit uses a control device to achieve compliance, the unit has a pre-control potential to emit (PTE) of the pollutant of greater than major source thresholds, and the emission limitation or standard is not exempt from the requirements of Part 64. Pre-control emissions of SO_2, NO_x, $PM/PM_{10,}$ H_2SO_4 mist and fluorides are each greater than 100 tpy. CAM requirements under 40 CFR 64.2(b) will be met for SO_2, NO_x, and $PM/PM_{10,}$ by compliance with the Acid Rain program and compliance with a post-November 15, 1990 NSPS standard. In accordance with Part 64, LG&E has submitted additional information on its CAM plan for H_2SO_4 mist and fluorides. Pursuant to 401 KAR 52:020, the plan will receive public notice to ensure federal enforceability.

TABLE 4.1 – CAM Plan for H_2SO_4 Mist and Fluorides

Applicable CAM Requirement	H_2SO_4 Mist	Fluorides
General Requirements	26.6 lb/hr 3 hour rolling average	1.55 lb/hr 3 hour rolling average
Monitoring Methods and Location	SO_2 CEMs plus initial source test, weekly coal sampling (as received) with quarterly coal composites. WESP liquid flow rate, voltage, secondary currents and/or operating parameters, in conjunction with initial performance tests to establish excursion and exceedance, shall be monitored	SO_2 CEMs plus initial source test, weekly coal sampling (as received) with quarterly coal composites
Indicator Range	Initial source testing to establish correlation to SO_2 and coal quality, then establish SO_2 CEM and coal range appropriate	Initial source testing to establish correlation to SO_2 and coal quality, then establish SO_2 CEM and coal range appropriate
Data Collection Frequency	Continuous SO_2 CEM, weekly coal sampling (as received) with quarterly coal composites	Continuous SO_2 CEM, weekly coal sampling (as received) with quarterly coal composites
Averaging Period	3 hour rolling	3 hour rolling
Recordkeeping	Coal quality information will be kept in a designated hard copy or electronic archive, plus CEM data system records	Coal quality information will be kept in a designated hard copy or electronic archive, plus CEM data system records
QA/QC	WFGD/WESP will be maintained and operated in accordance with manufacturer specifications and recommendations	WFGD/WESP will be maintained and operated in accordance with manufacturer specifications and recommendations

The use of a CEM that provides results in units of the appropriate standard for the pollutant of interest and meets the criteria in 40 CFR 64.3(d)(2) is considered presumptively acceptable CAM.

E. *Additional Monitoring and Testing Requirements*

The owner is required to conduct a performance test within 60 days after achieving the steady-state maximum production rate at which the affected facilities will be operated but not later than 180 days after initial start-up of such facilities on coal.

Under 40 CFR Part 60, Subpart Da, Emissions Unit 31 is required to be performance tested for particulate matter, sulfur dioxide and nitrogen oxides. 40 CFR Part 60, Subpart Da refers to 40 CFR 60.8 for testing requirements. As provided in 40 CFR 60.8, LG&E shall perform an initial compliance test for particulate matter, sulfur dioxide and nitrogen oxides per 40 CFR Part 60, Appendix A.

Emissions Unit 31 shall have CEMs for PM, SO_2, NO_x, CO, Hg, and diluent gases oxygen or carbon dioxide (CO_2), and a continuous opacity monitor (COM) for opacity monitoring.

Compliance with 40 CFR Part 75 will constitute compliance for the appropriate monitoring, testing, reporting, and record keeping requirements of 40 CFR Part 60, Subpart Da.

F. *PSD Requirements*

As stated earlier, 401 KAR 51:017, Prevention of Significant Deterioration (PSD) of air quality, applies to the proposed project. The project will be located in Trimble County, which is designated as “attainment” or “unclassified” for all ambient air quality standards. The project potential to emit (PTE) for all pollutants that trigger PSD review are listed in Table 4.2.

TABLE 4.2 – Project Potential to Emit for Pollutants Requiring PSD Review

Pollutant	PTE (tpy)	Significant Emissions Rate * (tpy)
Carbon monoxide (CO)	3,040.8	100
Particulate matter (PM/PM_{10})	567.4	25/10
Volatile organic compounds (VOC)	97.8	40
Fluorides	6.8	3
Sulfuric Acid (H_2SO_4) Mist	116.6	7

* Significant emission rate as given in 401 KAR 51:001 Section 1(221).

The proposed project constitutes a major modification for those pollutants listed in Table 4.1. PSD review applies to regulated pollutants for which there will be a net emissions increase that is significant as defined in 401 KAR 51:001, Section 1(221). For these pollutants, LG&E has performed a Best Available Control Technology (BACT) demonstration and an ambient air quality analysis as required by the Division. Each of these components of the PSD review process has been discussed in detail in the following sections. The proposed project is not significant with respect to NO_x, SO_2, lead, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds or any other PSD-regulated pollutant. Pursuant to Section 112(b)(6) of the FCAA, and 401 KAR 51:001 Section (1)(210) and (1)(221), no HAP is subject to PSD review.

5. BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

Pursuant to 401 KAR 51:017, Section 8, a major modification shall apply BACT:

1. For each regulated NSR pollutant that results in a significant net emissions increase at the source; and
2. For each proposed emissions unit at which a net emissions increase in the pollutant occurs as a result of a physical change or change in the method of operation of the unit.

The proposed project will result in a significant net emissions increase for sulfuric acid mist, fluorides, VOCs, carbon monoxide, and PM/PM_{10}. Therefore, each of these pollutants are subjected to a BACT review. BACT does not apply to the proposed project's emissions of NO_x and SO_2 LG&E has presented, in the permit application, a study of the best available control technology for applicable pollutants and each proposed emissions unit. The Division has reviewed the proposed control technologies in conjunction with information available in the U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database and other similar sources.

The applicant submitted a top-down BACT analysis following the U.S. EPA guidance, "New Source Review Workshop Manual" (U.S. EPA, October 1990). The key steps involved with the top-down BACT process are as follows:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate most effective controls considering economic, environmental, and energy impacts, and document results.
5. Select BACT.

A. BACT for New SPC Boiler

The following section summarizes the BACT determinations for the new SPC boiler. Using the top-down approach, the applicant selected various technologies for analysis of technical and practical feasibility, and then applied economic cost-effectiveness analyses where the top ranked technology was not selected. The following discussion from the application is provided below, and lists various technologies considered by the applicant in its BACT evaluation. A summary of the control technology determined to be BACT for each pollutant and each proposed emissions unit is presented in Table 5.1.

TABLE 5.1 – BACT Summary for New SPC Boiler (Emissions Unit 31)

ID No.	Emissions Unit/Process	Pollutant	Best Available Control Technology	Emission Standard
31	Supercritical Pulverized Coal Fired Utility Boiler Operation limitation: None	CO	Proper Boiler Design & Operation	0.1 lb/mmBtu (3 hour rolling average)
		PM/PM_{10}	PJFF (Filterable) & WFGD/WESP (Condensable)	0.018 lb/mmBtu (Filterable & Condensable) (average of three 1-hour tests)
		VOCs	Proper Boiler Design & Operation	0.0032 lb/mmBtu (3 hour rolling average)
		Fluorides	Proper Boiler Design & WFGD	1.55 lb/hr (3 hour rolling average)
		Sulfuric Acid Mist	Proper Boiler Design & WFGD/WESP	26.6 lb/hr (3 hour rolling average)

Note**: As described in Section 4(A) above, LG&E has also proposed an emission limitation of 0.015 lb/mmBtu (Filterable) on a 3-hour rolling average to meet U.S. EPA's proposed revisions to 40 CFR Part 60, Subpart Da.**

Nitrogen Oxide (NO_x)

BACT review for NO_x emissions control is not required for this Project. The Project is not considered a major modification for NO_x since there will not be a significant net increase of NO_x

emissions due to contemporaneous and creditable emission reductions of NO_x achieved at Emissions Unit 1 and emission limitations on NO_x imposed on the proposed project. Increased NO_x removal using the existing SCR on Emissions Unit 1 will provide the necessary emission reductions. Although BACT is not applicable, the applicant will utilize an SCR in conjunction with low NO_x burners on Emissions Unit 31 to reduce NO_x emissions to levels below those required by recent U.S. EPA proposed regulations regarding ozone, and to meet the most stringent NO_x emission limitation in the RBLC. The applicant is proposing that the NO_x emission limitation be set at 4.17 tons/day and 1,506.72 tons per year, which is based on a rate of 0.05 lb/mmBtu heat input on a 24-hour average. Hourly emissions are 348 lbs/hr on a 24 hour basis.

Sulfur Dioxide (SO_2)

BACT review for SO_2 emissions control is not required for this Project. The Project is not a major modification for SO_2 since there will not be a significant net increase of SO_2 emissions due to contemporaneous and creditable emission reductions of SO_2 achieved at Emissions Unit 1 and emission limitations on SO_2 imposed on the proposed project. Upgrades to the existing WFGD on Emissions Unit 1 will provide the necessary emission reductions necessary. However, the applicant is proposing to use a WFGD system as the SO_2 control technology for Unit 31. The applicant is proposing that the SO_2 emission limitation be set at 8.94 tons/day and 3,263.1 tons per year, which is based on a rate of 0.11 lb/mmBtu heat input on a 24-hour average. Hourly emissions are 746 lbs/hr on a 24 hour basis.

Carbon Monoxide (CO)

Carbon monoxide is formed as a result of incomplete combustion of fuel. For CO control, the applicant evaluated the available control technologies, which are: catalytic oxidation and the front-end technique of good combustion control. The most stringent CO control level available for a coal-fired boiler would be achieved with the use of a high temperature oxidation system added at the exhaust of the PJFF, which can remove approximately 95 percent of CO in the flue gas. However, as discussed below that control is considered technically infeasible for a coal-fired boiler. Based on the U.S. EPA BACT/RACT/LAER Clearinghouse for PC boilers and other technical materials, BACT determinations specify the following: good combustion practice, good combustion control and operation, proper design, and, in some cases, no controls. Proper boiler design and operation is BACT for CO emissions. The CO emissions shall not exceed 0.10 lbs/mmBtu from Emissions Unit 31 based on a 30 day rolling average. In addition, a short term limit of 0.5 lbs/mmBtu has been set to ensure protection of the NAAQS.

Catalytic oxidation is considered technically infeasible for an SPC boiler. The oxidation catalyst will not only oxidize CO and VOC, but will also oxidize a predominant portion of SO_2 to SO_3.

Combination of this SO_3 with SCR related ammonia injection will likely result in quick fouling of the air heater. Additionally, the acid gases and trace metals in the flue gas will poison the catalyst. There are also environmental impacts associated with the use of a catalytic oxidation system on an SPC boiler due to the oxidation of SO_2 to SO_3. There is also generation of hazardous waste from the spent catalyst. The Division therefore considers proper boiler design and operation as BACT for CO emissions.

Particulate (PM/PM_{10})

Particulate matter emissions from the new SPC boiler are primarily the result of ash content and other contaminants in the fuel. There are several control technologies for removing particulates from a gas stream but a PJFF and a dry ESP have the highest control efficiency of any of the particulate matter control options, and therefore, according to the "top-down" approach, must be considered first.

PJFF:

PJFF, which is essentially a baghouse, is an effective particulate control device used for meeting particulate emission limits on many coal fired boilers. PJFFs use fabric bags as filters to collect filterable particulates. The particulate-laden flue gas enters a PJFF compartment and passes through the filter bags. The collected particulate forms a cake on the bag, which can enhance the bag's filtering efficiency. The pressure drop across the bags increases as the thickness of the dust cake increases. At a predetermined set point, the filtering bags are cleaned, dislodging a large portion of the dust cake. These bag-cleaning cycles can vary from every 30 minutes to as long as 6 to 8 hours depending on ash loading, flue gas flow rate, filter cake properties, and other operational parameters. This Project will use a WFGD with the particulate control device to be located upstream instead of downstream of the WFGD, where the high moisture and high acidity of the flue gas from an eastern bituminous fuel present drawbacks to a PJFF. Use of a PJFF on high sulfur coal on a unit of this size has not been commercially proven long term in the US. In comparison to the dry ESP, the PJFF allows low emission rates to be maintained independent of the wide range of ash characteristics. Additionally, a PJFF allows the collected material on the bags to be in contacted with the flue gas more thoroughly and over a longer period of time as compared to an ESP. Mercury and SO_3 emissions come into contact with the collected ash, providing better control in the fabric filter baghouse systems as compared to an ESP.

Dry Electrostatic Precipitator (*ESP):*

Dry ESPs are the one of the dominant types of particulate collection device used on coal fired power plants. ESPs remove particulate by first charging fly ash particles. A utility ESP is essentially a large enclosure placed in the ductwork between the air heater and the ID fans. A series of parallel steel plates spaced approximately 12 to 16 inches apart is located within the

ESP. Discharge electrodes made of rigid steel pipe-like shapes or stretched wires are located between and parallel to the plates. A transformer rectifier (TR) sets a negative charge on the discharge electrodes and a positive charge on the plates to create a voltage differential. As the particulate-laden flue gas passes between the plates and the wires, the ash particles become negatively charged. The particles then migrate to the positively charged plate, where the ash accumulates. At various frequencies of time, rapping of the plates removes the accumulated ash from the plates. The impact of the rap shears the ash particles from the plate, causing the accumulated ash to fall into the hopper for collection. The ash handling system can then remove the ash for disposal or beneficial reuse. However, some of the dust is re-entrained and carried to the next ESP collection field downstream of the ESP.

ESP collection efficiency and cost are dependent on ESP size and characteristics of the fly ash. The ease with which an ESP can collect fly ash is a function of the particulate and flue gas properties, such as particle size, resistivity, flue gas temperature, and flue gas composition. Factors such as these, along with flue gas flow rate and particulate emission rate, determine the specific collection area or physical size of an ESP. The definition of specific collection area is the square feet of collection area per thousand actual cubic feet per minute (acfm) of flue gas treated. Operation also depends on the accuracy of electrode and plate alignment, uniformity and smoothness of gas flow through the ESP, rapping of the plates, and the size and electrical stability of the TR sets. A fly ash property that significantly affects the sizing of precipitators is ash resistivity. Resistivity is a measure of how easily the particulate acquires an electric charge. Fly ash resistivity varies with the moisture content, chemical composition, and temperature of the ash in the flue gas. The higher the ash resistivity, the more difficult it is to remove ash from the flue gas with an ESP. The major coal property affecting the fly ash resistivity for ESPs is the coal sulfur content. SO_3 formed during combustion of the coal coats the fly ash particles and lowers surface resistivity.

Wet Electrostatic Precipitator (WESP):

Wet electrostatic precipitators operate in much the same way as a dry or standard ESP; charging, collecting and finally cleaning. It is the cleaning step that is different. Cleaning is performed by washing the collection surfaces with water, in place of the usual mechanical means such as rapping of the collection plates. The delivery of the liquid or water can be made by a series of spray nozzles located in the control device or by condensing moisture from the flue gas on the collection surfaces. WESPs are able to control a larger variety of pollutants than an ESP can alone. WESPs are significantly better at controlling acid droplets and SO_3 gases. This has been supported by installations at acid production plants and other industrial sources that have highly acidic exhaust streams. Higher levels of SO_3 in the exhaust gas actually improve the collection efficiency of the WESP by reducing the electrical dust resistance. WESPs are also very effective in reducing re-entrainment of particles due to the constant cleaning of the collection surfaces by liquid. Additionally, WESPs can operate under much higher electrical power than ESPs, therefore enabling much greater reductions in sub-micron and condensable particulates.

According to information supplied in the application, when used in conjunction with wet flue gas desulfurization, WESPs are very effective in reducing SO_3, metals and other sub-micron particulates. WESPs are discussed further in the section on acid gas controls.

The applicant has proposed a PJFF (filterable) and a WESP (condensable) as BACT for PM/PM_{10}. The current market information and other sources in the RBLC support a determination that the control technologies being proposed for the new SPC boiler and an emission limit of 0.018 lb/mmBtu (filterable and condensable) based on an average of three 1-hour tests constitute BACT. The Division has reviewed the U.S. EPA BACT/RACT/LAER Clearinghouse for PC boilers and other recently issued coal fired utility air construction permits and has established that the proposed control technologies for filterable and condensable particulates are BACT.

Fluorides

The fluorides are present in the coal in trace amounts and generally emitted as hydrofluoric acid formed from hydrogenation of fuel-bound fluorides. The use of a WFGD scrubber is the proposed BACT control technology for fluoride emissions. For other coal fired projects, it has been determined that the wet scrubbers remove the fluorides (as hydrofluoric acid) as effectively as SO_2, allowing SO_2 to serve as a suitable surrogate for demonstrating the control of fluorides.

The Division has reviewed the U.S. EPA BACT/RACT/LAER Clearinghouse for PC boilers and other recently issued coal fired utility air construction permits and concurs that the proposed WFGD scrubber technology for SO_2 and a fluorides emission limitation of 1.55 lb/hr, based on a 3 hour rolling average, is considered BACT for the control of fluorides.

Sulfuric Acid (H_2SO_4) Mist

Sulfuric acid is present in the flue gases generated from combustion of coal because a fraction of the sulfur dioxide (SO_2) produced is further oxidized to sulfur trioxide (SO_3). SO_3 reacts with water in flue gas to form sulfuric acid vapor. Sulfuric acid can cause air heater fouling and equipment corrosion. When flue gas containing sulfuric acid vapor is cooled, sulfuric acid condenses to form a sub-micron aerosol mist that scatters light and can form a visible plume.

In addition to SO_3 formed during combustion, SCR catalysts used for NO_x control further oxidize a fraction of SO_2 to SO_3. The combination of furnace and SCR oxidation has the capability of producing significant quantities of SO_3. Furthermore, the SO_3 content in the furnace exit gas can limit SCR operation at lower unit load due to the lower flue gas temperatures resulting from the low load operation. The potential for forming ammonium sulfate salts that will foul active catalyst sites increases at the lower economizer outlet flue gas temperatures.

The applicant has assumed that the estimated sulfuric acid production rate basis is oxidation conversion of a total of 2.0 percent of SO_2 in the combustion process and across the SCR catalyst. The inclusion of a regenerative type air heater and a PJFF for particulate control will provide some reduction of H_2SO_4 emissions. Effective controls for H_2SO_4 include post-combustion controls. Potential controls include lime-based, semi-dry scrubbers (SDS), wet WESPs, and alkali injection systems using one of several possible chemicals. Evaluation of these technologies is discussed below.

Semi-Dry Scrubber Systems:

The gas temperature leaving a lime-based SDS is lowered below the sulfuric acid dew point, and significant SO_3 removal will be attained as the condensed acid reacts with the alkaline reagent. By removing SO_3 in the flue gas, the sulfuric acid mist can be reduced. Since this is an eastern bituminous fuel, WFGD technology is required to control SO_2 emissions; hence, the SDS would not be used for SO_2 control. An SDS has never been installed solely for the purpose of sulfuric acid mist control on a coal fired utility boiler. Since the control of SO_2 is not a co-benefit, the Division concurs with the Applicant that it is not economically feasible to install SDS for sulfuric acid mist removal.

WESP Systems:

A WESP is typically installed downstream of a wet scrubber where the flue gas is saturated with moisture. A WESP allows sulfuric acid mist to condense and be collected as particulate or absorbed into the water stream. The WESP also provides the advantage of additional control of fine particulates and mercury that may pass through the upstream control systems. While the potential for reductions in these emissions is not directly quantified, the ability of the WESP to act as a potential polishing device provides additional certainty that the low emission rates for the Project can be met. Therefore, the applicant has considered the WESP technically viable option for this Project.

Alkali Injection Systems:

Injection of finely divided alkalis into flue gas has been demonstrated for removal of SO_3 from flue gases. Most commercial experience is from units firing high-sulfur oil where trace metals, mainly vanadium, increase oxidation of SO_2. Magnesium-based compounds have been used successfully for decades for capture of SO_3 in oil-fired units. As coal fired units have been retrofitted with SCR systems, interest in the injection of alkali compounds directly into the flue gas duct of a unit has increased. Compounds such as sodium bisulfite and hydrated lime have recently been tested on large coal fired units with reported results showing the achievement of high control efficiencies of SO_3. This experience has demonstrated that alkali injection is a cost-effective method for high efficiency control of sulfuric acid mist.

A review of the information contained in the RBLC and other permitting information sources indicates the following: The lowest emission limit currently permitted for an eastern bituminous PC fired plant is for the Thoroughbred facility to be located in the Commonwealth of Kentucky. The permit reflects an emission limit for H_2SO_4 of 0.00497 lb/mmBtu using a WESP as the control technology. Prairie State Generating Station is a PC fired plant and was also permitted for an eastern bituminous coal in the State of Illinois. The permit reflects an emission limit for H_2SO_4 of 0.005 lb/mmBtu using a WESP as the control technology. Another eastern bituminous PC fired plant recently permitted is the Longview facility to be located in the State of West Virginia. The permit reflects an emission limit for H_2SO_4 of 0.0075 lb/mmBtu using dry sorbent injection as the control technology.

The applicant has proposed the use of good combustion controls and inclusion of a WESP downstream of the WFGD controls as BACT to achieve a limit of 26.6 lb/hr based on a 3-hour rolling hour average, which is based on a rate of 0.004 lb/mmBtu. The selection of the WESP is based on the ability of this device to provide some additional control margin in achieving the emission limits for PM/PM_{10} and mercury. While the alkali injection system can achieve the desired H_2SO_4 limits, this technology does not provide any other additional emission control benefits that the WESP offers. The Division concurs that the proposed control technology and emission rate constitute BACT for the new SPC boiler.

<u>Startup and Shutdown</u>

The emission limitations identified above do not apply during periods of startup and shutdown of the new SPC boiler (Emissions Unit 31). The BACT determinations and associated emissions levels discussed above were determined based on normal operating conditions that allow the use of pollution control technologies. Some of these control technologies cannot be used, to their full or partial potential during startup or shutdown for safety and other reasons. Pursuant to 401

KAR 51:017, emissions during startup and shutdown shall be included in determining compliance with tons per year limits specified in the draft permit and the owner or operator shall utilize good work and maintenance practices and manufacturer's recommendations to minimize emissions during, and the frequency and duration of, such startup and shutdown events. The Division concurs that these practices and the supercritical design of boiler constitute BACT for startup and shutdown operations of the new SPC boiler.

B. PM/PM$_{10}$-Material Handling

Coal and reagent handling requirements will be met by existing facilities onsite with some modifications to handle the coal blending and dust control measures required to comply with BACT requirements. Dust control improvements will ensure that transfer points are enclosed or have wet spray dust suppression. The proposed BACT materials handling controls for other new or modified facilities or activities are summarized in the Table 5-2. Fly ash handling will use pneumatic conveying with fabric filter as the final stage of transport air cleaning prior to discharge to the atmosphere.

C. PM/PM$_{10}$-Cooling Towers

The proposed cooling tower BACT for this project is the utilization of the existing natural draft cooling tower (0.008 percent drift) for Emissions Unit 31, with Emissions Unit 1 cooling water being redirected from the existing natural draft cooling tower to a new 11-cell linear mechanical draft cooling tower (LMDCT) with a 0.0005 percent drift rate. The Division has established that the proposed technology and emission rates are BACT for the cooling towers.

D. Auxiliary Steam Boiler

The auxiliary steam boiler will be a 40 mmBtu/hr, unit. The boiler will minimize emissions by utilizing low NO_x burners and firing ASTM Grade No. 2-D S15 or equivalent fuel oil. The Division considers the proposed design and operation of the boiler and hours of operation for the boiler capped at 1,000 hours per year or less constitute BACT.

E. Backup Diesel Generator

The applicant has proposed to install a 1.25 MW backup diesel generator. The Division considers the use of ASTM Grade No. 2-D S15 or equivalent fuel oil and limiting the operation of the generator to 1,000 hours or less per year constitutes BACT.

F. Emergency Diesel Fire Water Pump Engine

Similar to the backup diesel generator, the applicant has proposed to install one emergency diesel firewater pump engine. The Division considers the use of ASTM Grade No. 2-D S15 or equivalent fuel oil and limiting operation of the pump to 52 hours or less per year constitutes BACT for the fire pump.

G. Project Emission Units

The following table identifies emissions unit and control devices affected by the Project:

TABLE 5.2 – Project Emission Units

Emissions Units		Air Pollution Control Devices	
ID. No.	**Description**	**ID. No.**	**Description**
31	6,942 mmBtu/hr Supercritical Pulverized Coal Fired Boiler; ASTM Grade No. 2-D S15 or equivalent fuel oil for startup and stabilization	None	Equipped with SCR, Baghouse PJFF, WFGD & WESP
32	40 mmBtu/hr Auxiliary Steam Boiler firing ASTM Grade No. 2-D S15 or equivalent fuel oil	None	None
33	Emergency Backup Diesel Generator firing ASTM Grade No. 2-D S15 or equivalent fuel oil	None	None
34-35	Active Northwest Fossil Fuel Pile “A” and Northeast Fossil Fuel Pile “B”	None	Compaction and Water Suppression
7-9	Fossil Fuel Handling Operations	36-39	Dust Collectors, Partial Enclosure, Low Pressure Drop, Water Suppression, and Hoods
11	Limestone Handling and Processing	40	Dust Collector, Partial Enclosure, Low Pressure Drop, Water Suppression, and Hoods
20	Existing Natural Draft Cooling Tower for Emissions Unit 31	None	0.008% Drift Eliminators
41	Linear Mechanical Draft Cooling Tower for Emissions Unit 1	None	0.0005% Drift Eliminators
NA	Fly Ash Storage Silos	42	Dust Collectors

The units listed above are considered separate emissions units because they are individual activities that emit or have the potential to emit regulated air pollutants. Emissions unit is defined at 401 KAR 51.001 Section 1(66) as any part of a stationary source that emits or has the potential to emit any regulated NSR air pollutant. This term is not meant to alter or affect the definition of the term "unit" for purposes of Title IV of the Act [40 CFR 70.2]. However, similar emissions units were combined in this permit into one emissions unit ID to simplify the permit. These emissions units have the same applicable requirements.

H. Insignificant Activities/Applicable Regulations

401 KAR 52:020 Section 6 allows sources to separately list in the permit application activities that qualify as "insignificant" based on potential emissions. Insignificant activities have the potential to emit below 5 tpy for all nonhazardous air pollutants and ½ ton per year for combined HAPs. The activities that qualify as "insignificant" are not exempt from compliance demonstration and applicable requirements or any other requirements of the PSD/Title V permit. The following table describes the insignificant activities associated with the Project.

TABLE 5.3 – Project Insignificant Activities

Insignificant Activities Description and Applicable Regulation(s)	
1. Two station #2 fuel oil tanks, each 100,000 gallons (401 KAR 59:050), and auxiliary boiler day tank storing #2 fuel oil with a size of 16,000 gallons. General recordkeeping requirements - 40 CFR 60.116b(a) and (b)	401 KAR 59:050 40 CFR 60.116b(a) and (b)
2. Metal degreaser using a maximum throughput of 832 gallons/year solvent.	NA
3. 3,000 gallon unleaded gasoline storage tank.	NA
4. 3,000 gallon diesel storage tank.	NA
5. 1,100 gallon used oil storage tank.	NA
6. 1,100 gallon #1 fuel oil tank.	NA
7. Fly ash collection system	401 KAR 59:010
8. Infrequent evaporation of boiler cleaning solutions.	NA
9. Infrequent burning of de minimis quantities of used oil for energy recovery.	NA
10. Paved and Unpaved Roads.	401 KAR 63:010
14. Gypsum Storage Piles	401 KAR 63:010
15. Coal and Limestone Storage Piles (Inactive Outdoor Piles)	401 KAR 63:010
16. Bottom Ash and Debris Collection Basin	401 KAR 63:010
17. Bottom Ash Reclaim Operation	401 KAR 63:010
18. Three dry bulk fly ash transport trailers	401 KAR 59:010
19. Maintenance Shop Activities	NA
20. Miscellaneous Water Storage Tanks	NA
21. Anhydrous Ammonia Storage Tanks	401 KAR 68
22. Fire Water Pump Engines	NA
23. Three dry bulk fly ash transport trailers	401 KAR 59:010

I. Applicable Requirements

Table 5.4 lists the emissions units and their applicable requirements for the Project.

TABLE 5.4 – Project Applicable Requirements

Emissions Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
31 750 MW SPC-Fired Boiler Primary Fuel: Coal	PM/ PM10	0.015 lb/mmBtu (filterable) based on a 3-hour rolling average 0.018 lb/mmBtu (filterable & condensable) based on an average of 3 1-hour tests	401 KAR 59:016 Section 3(1)(b) & 6(1) 401 KAR 60:005 Section 3(1)(c) 401 KAR 51:017 (filterable and condensable only) 40 CFR Part 60, Subpart Da 40 CFR Parts 75	Continuous Emissions Monitoring	Reports for all required monitoring	Initial and annual performance testing/ U.S. EPA Reference Methods 5, 9, 201 or 201A, & 202, or alternative method approved in permit, or other approved alternative method
	SO_2	8.94tpd 1.2 lb/mmBtu and 90% reduction or 70% reduction when emissions are less than 0.6 lb/mmBtu, based on 30-day rolling average 2.0 lb/MWh gross energy output, based on 30-day rolling average	401 KAR 59:016, Section 4(1) 401 KAR 60:005 Section 3(1)(c) 40 CFR Part 60, Subpart Da 40 CFR Parts 75 & 72	Continuous Emissions Monitoring	Reports for all required monitoring	Initial Performance Testing using CEMs

Emissions Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
	NO_x	4.17 tpd 0.6 lb/mmBtu (65% reduction,) based on a 30-day rolling average 1.6 lb/MWH gross energy output, based on a 30 day rolling average 1.0 lb/MWh gross energy output, based on a 30-day rolling average	401 KAR 59:016 Sections 5(1)(c), 6(2), 5(2) 401 KAR 60:005 Section 3(1)(c) 40 CFR Part 60, Subpart Da 40 CFR Parts 75 &72	Continuous Emissions Monitoring	Reports for all required monitoring	Initial Performance Testing using CEMs
	CO	0.10 lb/mmBtu based on a 30 day rolling average 0.5 lb/mmBtu on a 3-hr rolling average.	401 KAR 51:017	Continuous Emissions Monitoring	Reports for all required monitoring	Initial Performance Testing using CEMs
	VOC	0.0032 lb/mmBtu based on a 3-hour rolling average	401 KAR 51:017	CO CEM use CO emissions as surrogate for VOC emissions	Reports of all required monitoring	Initial and annual Performance Tests/EPA reference methods 18 or 25
	Fluoride	1.5 lb/hr based on a 3 hour-day rolling average	401 KAR 51:017 40 CFR Part 64	SO_2 CEMs, use SO_2 emissions as surrogate for fluoride emissions	Reports of all required monitoring	Initial Performance Tests/EPA reference method 26A

Emissions Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
	Sulfuric Acid Mist	26.6 lb/hr based on a 3-houry rolling average	401 KAR 51:017 40 CFR Part 64	SO_2 CEMs, WESP liquid flow rate, voltage, secondary currents and/or operating parameters,	Reports for all required monitoring	Initial Performance Tests/EPA reference method 8
	Hg	13 x 10 (E-6) lb/MWh gross energy output, based on a 12-month rolling average Formula per 40 CFR 60.45a	401 KAR 60:005, Section 3(1)(c) 40 CFR Part 60, Subpart Da	Continuous Emissions Monitoring	Reports for all required monitoring	Initial Performance Tests/EPA reference method 29
	Pb	0.55 tpy	401 KAR 51:017	PM CEMs, use PM emissions as surrogate for Pb emissions	Reports for all required monitoring	Initial and annual performance tests/EPA Methods 12 or 29
32 Auxiliary Steam Boiler D	PM/ PM10	0.03 lb/mmBtu	401 KAR 59:015, Section 4(1)(c) 401 KAR 51:017 401 KAR 60:005, Section 3(1)(e) 40 CFR Part 60, Subpart Dc 40 CFR 60.43c(e) (proposed) 40 CFR Part 63, Subpart DDDDD	Monitor hours of operation and fuel oil sulfur content and heating value	Reports for all required monitoring	Certification per 40 CFR 63.7506

Emissions Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
	CO	400 ppmv, on a dry basis corrected to 3% oxygen, based on a 3-hour average	401 KAR 51:017 40 CFR Part 63, Subpart DDDDD	Monitor hours of operation and fuel oil sulfur content and heating value	Reports for all required monitoring	Certification per 40 CFR 63.7506
	SO_2	Use of ASTM Grade No 2-D S15 or equivalent fuel oil	401 KAR 59:015 Section 5(1)(b) 401 KAR 51:017 401 KAR 60:005, Section 3(1)(b)	Monitor hours of operation and fuel oil sulfur content and heating value	Reports of all required monitoring	Certification per 40 CFR 63.7506
	HCl	0.0005 lb/mmBtu	40 CFR Part 63, Subpart DDDDD	Monitor hours of operation and fuel oil sulfur content and heating value	Reports for all required monitoring	Certification per 40 CFR 63.7506
	All Pollutants	Use of ASTM Grade No 2-D S15 or equivalent fuel oil Operate, except for testing purposes, only when Emissions Unit 31 is operating at less than 50% load Operate no more than 1,000 hours in any 12- month period	401 KAR 51.017	Monitor hours of operation and fuel oil sulfur content and heating value	Reports for all required monitoring	

Emissions Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
33 Backup Diesel Generator	Formaldehyde	580 ppbvd, at 15% oxygen, based on three test runs	401 KAR 63:002 40 CFR Part 63, Subpart ZZZZ	Continuous parameter monitoring or alternative method	Reports for all required monitoring	Initial performance testing, then semiannual thereafter, provided that if compliance demonstrated in two consecutive semiannual tests, annual thereafter
	All pollutants	Use of ASTM Grade No 2-D S15 or equivalent fuel oil Operate, except for testing purposes, only when Emissions Unit 31 is operating at less than 50% load Operate no more than 1,000 hours in any 12- month period	401 KAR 51:017			
34-35 Fossil Fuel Handling Operations – Coal Piles “A & B”	PM	None	401 KAR 51:017 401 KAR 63:010	Maintain Records of Coal received and processed and weekly (Monday – Friday) visual observation	50:055 Section 1, 52:020 Section 21 & 22	Method 9

Emissions Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
36-39 Fossil Fuel Handling Operations, Dust Control Devices, and Associated Systems	PM	None	401 KAR 51:017 401 KAR 60:005 40 CFR Part 60, Subpart Y	Maintain Records of Coal received and processed and weekly (Monday – Friday) visual observation	50:055 Section 1, 52:020 Section 21 & 22	Method 9
40 Limestone Handling and Processing, Dust Control Device	PM	None	401 KAR 51:017 401 KAR 60:670 40 CFR Part 60, Subpart OOO	Maintain Records of Limestone received and processed and weekly (Monday – Friday) visual observation	50:055 Section 1, 52:020 Section 21 & 22	Method 9
20, 41 Cooling Towers	PM	401 KAR 63:010, Section 3	401 KAR 51:017 401 KAR 63:010	Maintain Records of Maximum pumping capacity and total dissolved solids	50:055 Section 1, 52:020 Section 21 & 22	CTIACT-140. Monthly measurement of total dissolved solids content of circulating water
42 Fly Ash Loading System	PM	401 KAR 59:010	401 KAR 51:017 401 KAR 63:010	Maintain records of ash conveyed and visual observation		Method 9

6. AIR QUALITY IMPACT ANALYSIS

Pursuant 401 KAR 51:017 Section 11, the applicant has provided an analysis of ambient air quality in the area that the major modification will affect for each regulated pollutant for which a NAAQS has been established and for which there will be a significant net emissions increase. Pursuant to 401 KAR 51:017 Section 12, the applicant has provided an analysis of the air quality impacts of the major modification. Pursuant to 401 KAR 51:017 Section 7(5)(a), the Division may exempt a project that would result in a net emissions increase of less than 100 tpy of VOCs from an ambient air impact analysis, including the gathering of ambient air quality data.

The purpose of these analyses is to demonstrate that allowable emissions from the proposed project will not cause or contribute to air pollution in violation of:

1. A national ambient air quality standard in an air quality control region; or
2. An applicable maximum allowable increase over the baseline concentration in an area.

A. Modeling Methodology

The application contains ISCST3 air dispersion modeling analysis for PM/PM_{10} and CO to determine the maximum ambient concentrations attributable to the proposed project for each of these pollutants for comparison with:

1. The significant impact levels (SIL) found in 40 CFR 51.165 (b)(2).
2. The Significant Air Quality Impact levels (SAI) found in Regulation 401 KAR 51:017, Section 6 Section 7(5).
3. The Class I and Class II Ambient Air Increments found in Regulation 401 KAR 51:017, Section 2.
4. The National Ambient Air Quality Standards (NAAQS) found in Regulation 401 KAR 53:010, Ambient air quality standards.

All applicable ambient air quality concentration values are presented in Table 6.1. Based on U.S. EPA procedures, if the maximum predicted impacts for any pollutant are found to be below the SILs, it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling would be required for such a pollutant. The applicant may also be exempted from the ambient monitoring data requirements if the impacts are below the significant monitoring concentrations or SAI. The SAI levels determine if the applicant will be required to perform pre-construction monitoring. If the modeled impacts equal or exceed the SAI levels, pre-construction monitoring may be required. As shown in the application, the modeled impacts as compared to the SAI levels were not exceeded for the PM_{10} 24-hour and annual or CO 1-hour & 8-hour periods. However, if existing air quality data is available that is representative of the air quality area in question an exemption may be granted. Based on the information contained in the air permit application, the applicant requested a waiver from ambient monitoring. The Division reviewed the air permit application and associated air dispersion modeling, determined the location of the existing monitors, quality of the data, and the data’s correctness all met the requirements listed in the NSR guidance manual. Therefore, the applicant is exempted from the pre-construction ambient monitoring data requirements.

TABLE 6.1 – Ambient Air Quality Concentration Values

Pollutant	Averaging Period	SIL ($\mu g/m^3$)	SAI ($\mu g/m^3$)	PSD Class II Increments ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
PM/PM_{10}	Annual 24-hour	1 5	NA 10	17 30	50 150
CO	8-hour 1-hour	500 2000	575 NA	NA NA	10000 40000

The applicant used the Industrial Source Complex Short Term model (ISCST3, Version 02035) in the analysis. The ISCST3 model fulfills the requirements of Supplement C of the Guideline on Air Quality Models (Appendix W to 40 CFR Part 51). All of the parameters used in the modeling analysis for each pollutant appear satisfactory and consistent with the prescribed usage for this model. Per U.S. EPA guidance, the ISCST3 model was run with the regulatory default option in a sequential hourly mode using five years of meteorological data. Surface data and concurrent upper air data used were based on weather observations taken at the National Weather Service (NWS) station at Louisville, Kentucky and Dayton, Ohio, respectively, from 1987 to 1991. To reflect the modelled impacts used for determining compliance with the SIL and SAI, a short term permit limit of 0.5 lbs/mmBTUtu on a three hour average has been set for this permit. This limit is to ensure protection of the NAAQS and is not meant to be a BACT limit.

With respect to the Class I modeling the applicant used the CALPUFF model with refined inputs to better predict possible impacts for the particular region in question. The Class I modeling protocol document governing the methodology used is provided in Appendix N of the application, detailed documentation of the modeling inputs, the techniques used, and results are provided in Appendix O of the application, and electronic modeling files are contained in Appendix P of the application. The Class I modeling contains the appropriate mesoscale meteorological (MM) data with the concurrent surface, upper air, and precipitation data for years 1990, 1992, and 1996.

B. Modeling results - Class II Area Impacts

The proposed facility will be located in Trimble County, a Class II area. The applicant modeled the impact of the emissions from the proposed project on the ambient air quality and the results of the modeled impacts on the Class II area have been presented in Table 6.2. Since EPA has proposed but not finalized $PM_{2.5}$ implementation guidance, the Division has utilized PM_{10} as a surrogate for $PM_{2.5}$ in the interim prior to final guidance.

The modeling results show that the maximum impacts from the proposed facility for PM_{10} and CO are less than the U.S. EPA prescribed significant impact levels (SIL) and no further analyses are required. Detailed descriptions of the modeling inputs and results are in Section 4 of the application.

Trimble County has not been designated a $PM_{2.5}$ nonattainment area. It does border Clark County Indiana a $PM_{2.5}$ nonattainment area. An air dispersion modeling analysis has been performed to include part of Clark County, Indiana. Specifically, the results from the Class II PM10 air dispersion modeling indicated that there was no significant impact of PM10 emissions on a 24-hour or annual basis on the surrounding area including part of Clark County, Indiana. Additionally, it should be noted that the Cincinnati $PM_{2.5}$ nonattainment area is located approximately 40 miles northeast of the proposed Unit 2 project, is not bordering Trimble County, and due to the distance from the proposed project, would likely not have a significant impact on the Cincinnati $PM_{2.5}$ nonattainment area.

TABLE 6.2 – Applicant's Modeled Predicted Impacts

Pollutant	**Averaging Period**	**SIL** ($\mu g/m^3$)	**SAI** ($\mu g/m^3$)	**Max Impact of Emission** ($\mu g/m^3$)	**Preconstruction Monitoring Required**
PM/PM_{10}	Annual 24-hour	1 5	NA 10	0.90 4.74	NA No
CO	8-hour 1-hour	500 2000	575 NA	118.99 453.41	No NA

C. Modeling Results - Class I Area Impacts

The nearest federally designated Class I area to the project site is Mammoth Cave National Park. The nearest park boundary is approximately 155 km (96 miles) to the South-Southwest of the proposed project and was analyzed by the applicant using the CALPUFF model at the request of the Federal Land Manager (FLM) and the Division. The Class I modeling protocol document governing the methodology used is provided in Appendix N of the application, detailed documentation of the modeling inputs, the techniques used, and results are provided in Appendix O of the application, and electronic modeling files are contained in Appendix P of the application. Table 6.3 lists the modeled increment consumption for the proposed source and illustrates no Class I increments will be exceeded. In addition, the Division has reviewed the predicted change in visibility and total nitrogen and sulfur deposition impacts that may result from the project emissions.

The permit contains daily limits on NO_x and SO_2 emission rates to minimize degradation of visibility. There is one day in three years that has been predicted to slightly exceed the 5%

visibility change (modeled value was less than 5.05%) and zero days exceeding a 10% change, set as screening values. For total deposition, only the year 1990 slightly exceeds the total sulfur screening value. On January 18, 2005, the FLM issued a letter indicating based on the Class I modeling submitted with the application, that there would be no adverse impacts from the project at Mammoth Cave National Park.

TABLE 6.3 – Modeled PM_{10} Class I Increment Consumption

Pollutant (PM/PM_{10})	**Averaging Period**	**Class I Increment** ($\mu g/m^3$)	**Project Class I Increment Consumption** ($\mu g/m^3$)
1990	Annual	4	0.0022
	24-hour	8	0.0437
1992	Annual	4	0.0021
	24-hour	8	0.0440
1996	Annual	4	0.0019
	24-hour	8	0.0615

7. ADDITIONAL IMPACTS ANALYSIS

401 KAR 51:017 Section 13 requires an applicant for a PSD permit to provide an analysis of the impairment to visibility, soils and vegetation that will occur as a result of the project and projected growth associated with the project.

A. Growth Analysis

The proposed project, as reported in the application, will employ approximately 600 to 700 personnel during the construction phase. The project will employ approximately 30 to 40 people on a permanent basis. It is a goal of the project to hire from the local community where possible. There should be no substantial increase in community infrastructure, such as additional school enrollments. The proposed project is also not expected to result in an increase in secondary emissions associated with non-project related activities.

B. Soils and Vegetation Impacts Analysis

The proposed project is located at the existing Trimble County Generating Station. No significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. It is concluded that no adverse impacts will occur to sensitive vegetation, crops or soil systems as a result of operation of the proposed project.

C. Visibility Impairment Analysis

As discussed previously in Section 6 the visibility at Mammoth Cave National Park was reviewed using the visibility function in the CALPUFF model. The projected change in visibility associated with the operation of the proposed facility has been determined to be minimal as a result of the multiple control technologies that will be utilized. However, Section 6 of the application contains a visibility analyses for the nearby City of Bedford, Kentucky.

8. CONCLUSION AND RECOMMENDATION

In conclusion, considering the information presented in the application, the Division has made a preliminary determination that the proposed project meets all applicable requirements:

1. All the emissions units are expected to meet the requirements of BACT for each regulated pollutant for which there will be a significant net emission increase. Additionally, each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emission standard and standard of performance under 40 CFR Parts 60, 61, 63 and 64 will also be met.

2. Emissions from the proposed project will not cause or contribute to a violation of the NAAQS or any Class I or Class II Ambient Air Increments. Ambient air quality impacts on Class II area are expected to be below the significant impact levels. No adverse impact is expected on any Class I area.

3. Impacts on soil, vegetation, and visibility have been predicted to be minimal.

The Division has made a preliminary determination to approve the application. A draft permit to authorization the construction and operation of the project at the Trimble County Generating Station located west of Bedford in Trimble County, Kentucky, containing conditions which ensure compliance with all the applicable requirements listed above has been prepared by the Division and issued for public notice and comment. A copy of this preliminary determination will be made available for public review at the following locations:

1. Affected public at the Trimble County Clerk's office.

2. Division for Air Quality, 803 Schenkel Lane, Frankfort.

3. Division for Air Quality, Florence Regional Office, 8020 Veterans Memorial Drive, Suite 110, Florence, KY 41042-8960.

CREDIBLE EVIDENCE:

This permit contains provisions which require that specific test methods, monitoring or recordkeeping be used as a demonstration of compliance with permit limits. On February 24, 1997, the U.S. EPA promulgated revisions to the following federal regulations: 40 CFR Part 51, Sec. 51.212; 40 CFR Part 52, Sec. 52.12; 40 CFR Part 52, Sec. 52.30; 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12, that allow the use of credible evidence to establish compliance with applicable requirements. At the issuance of this permit, Kentucky has only adopted the provisions of 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12 into its air quality regulations.